BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) for Approval of Demand Response Programs, Activities and Budgets for 2012 through 2014.	Application 11-03-003 (Filed March 1, 2011)
Application of San Diego Gas & Electric Company (U 902 M) for Approval of Demand Response Programs and Budgets for Years 2012 through 2014.	Application 11-03-002 (Filed March 1, 2011)
Application of Pacific Gas and Electric Company for Approval of 2012-2014 Demand Response Programs and Budgets (U39E).	Application 11-03-001 (Filed March 1, 2011)

REPLY BRIEF OF
THE DIVISION OF RATEPAYER ADVOCATES

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SEPTEMBER 9, 2011

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REPLY BRIEF OF
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1. INTRODUCTION

Pursuant to Rule 13.11 of the California Public Utility Commission's ("CPUC" or "Commission") Rules of Practice and Procedure, the schedule adopted in the May 13, 2011 *Joint Assigned Commissioner And Administrative Law Judge's Ruling And Scoping Memo* ("Scoping Memo"), and the August 1, 2011 *Administrative Law Judge's Ruling Providing Guidance on Briefs*, the Division of Ratepayer Advocates ("DRA") hereby submits this reply brief in the above captioned proceedings. The scoping memo sets forth a due date for reply briefs on September 9, 2011; thus, this filing is timely.

Briefs were filed in this proceeding on August 22, 2011. The applicants, the three investor-owned utilities ("IOUs") consisting of Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE") and San Diego Gas Electric Company ("SDG&E") each submitted opening briefs. In addition, The Utility Reform Network ("TURN"), Utility Consumers' Action Network ("UCAN"), California Large Energy Consumers Association ("CLECA"), Alliance for Retail Energy Markets ("AReM"), the California

Independent System Operator ("CAISO"), EnerNOC Inc. ("EnerNOC"), the Demand Response Aggregators[1] ("DR Aggregators"), North America Power Partners, LLC ("NAPP"), CALMAC Manufacturing Corporation ("CALMAC"), Ice Energy, Inc. ("Ice Energy"), and California Energy Storage Alliance ("CESA") all submitted opening briefs. DRA responds to several issues raised in parties' briefs below.

2. OVERARCHING ISSUES

2.1. EVALUATING COST EFFECTIVENESS

2.1.1. Response to PG&E

PG&E's opening brief continues to claim its "alternate A factor should be used by the Commission as it provides a better estimate of PG&E's avoided costs."[2] As DRA argued in its opening brief, these arguments should be rejected.

If the Commission were to adopt PG&E's arguments, it would essentially undo all of the work done by Energy Division, its consultant, Energy and Environmental Economics, Inc. ("E3"), and stakeholders to develop a common cost-effectiveness evaluation model. Moreover, use of PG&E's proprietary Loss of Load Probability ("LOLP") study is unreliable in terms of estimating PG&E's avoided costs for the 2012-2014 Demand Response Cycle. First, as mentioned in DRA's opening brief, PG&E's LOLP study was conducted in 2006[3] and should be considered dated for the purposes of evaluating the proposals in the 2012-2014 Demand Response Program Cycle Applications.[4] Second, and most importantly, as described in the protocols adopted in D.10-12-024, PG&E's LOLP model requires "substantial amounts of generator-specific information, which is especially difficult to gather for the substantial amount of new private generation being added to serve California."[5] There is no doubt that PG&E's LOLP model, conducted in 2006, contains generator-specific information that has not been updated to account for the substantial amount of new private generation that has been added

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[1] A joint filing consisting of third-party aggregator companies, Comverge, EnerNOC, and EnergyConnect.

[2] PG&E Opening Brief, p. 5.

[3] Ex. DRA-1/Ex. DRA-1c, p. 2-6.

[4] Ex. DRA-1/Ex. DRA-1c, p. 2-6, lns. 11-15.

[5] D.10-12-024, Attachment 1, p. 23 (mimeo).

since 2006. Therefore, PG&E's generator-specific information, used in PG&E's LOLP study, is deficient and cannot possibly provide a good estimate of PG&E's avoided costs.

As the Commission's preferred approach, E3's method for calculating the A factor is clearly a more dependable indicator to evaluate avoided costs.[6] Even so, PG&E rejects E3's method in favor of its proprietary methods. PG&E further says "the Default DR Reporting Template [E3's method for calculating A factor] only considers electric load in earlier periods.[7] However, as explained in D.10-12-024. the Commission prefers the approach of basing the likelihood of an outage on load levels alone over the approach of developing a LOLE/LOLP model:

> In this calculation as in many others, the advantage of simplicity and transparency outweigh the advantages of proprietary traditional LOLE/LOLP models.[8]

Therefore, the Commission's adopted protocols have already established the advantage of simplicity and transparency, which is exhibited by E3's method for calculating the A factor, outweighing the advantages of proprietary traditional LOLP models such as PG&E's LOLP model. Furthermore, PG&E's LOLP cannot meet the requirement, set forth in the protocols in D.10-12-024, to "be shared in the public domain, along with sufficient documentation of their derivation to allow them to be verified independently."[9] PG&E's witness Bill Gavelis admitted that PG&E's LOLP model is a proprietary model called PROSYM that cannot be provided to the public because it belongs to a consulting company called Global Energy.[10] In its opening brief, PG&E claims that because "DRA did not avail itself of its discovery rights by requesting the model inputs or access to the model that was used is not evidence that PG&E's LOLP study is not verifiable."[11] PG&E's argument should be disregarded. That DRA did not request access to PG&E's LOLP model is simply based on DRA's knowledge that PG&E's LOLP model is

[6] D.10-12-024, Attachment 1, p. 23 (mimeo).

[7] PG&E Opening Brief, p. 5.

[8] D.10-12-024, Attachment 1, p. 23 (mimeo).

[9] Id., p. 23.

[10] Tr. Vol. 1, 40:9-12 (PG&E/Gavelis).

[11] PG&E Opening Brief, p. 8.

proprietary and could not have been provided to DRA, as evidenced by the response provided by PG&E's witness Bill Gavelis during hearings.[12]

PG&E's LOLP model should not be considered for inclusion in the DR benefits analysis because it uses dated—and therefore unreliable—generator-specific information and because it does not meet the transparency requirement set forth in the protocols in D.10-12-024. As a policy matter, allowing PG&E—or any IOU—to completely deviate from the DR Template using proprietary models would undo years of the Commission's effort to develop a consistent and transparent method with which to evaluate cost-effectiveness.

2.1.2. Response to SCE

In its opening brief, SCE states that "cost-effectiveness is certainly an important aspect of program evaluation, but not to the exclusion of other important considerations."[13] SCE cited other considerations that were provided in the Scoping Memo, including: "reasonableness of program and portfolio design, measured in terms of cost effectiveness, track record, future performance, cost, flexibility and versatility, adaptability, locational value, integration, consistency across the Joint Applicants' applications, simplicity, recognition, environmental benefits, consistency with Commission policies and general policies affecting revenue allocation."[14]

As stated in DRA's opening brief, DRA does not dispute that there are other factors listed in the Scoping Memo. Since the DR Template considers most of the benefits and costs of consequence, DR cost-effectiveness results should be the Commission's primary and necessary test in determining whether a DR program should be approved. In DRA's view, cost-effectiveness ***should be the most important factor*** in determining whether adoption of a program is a necessary and beneficial ratepayer investment. Therefore, DRA restates its recommendations to reject SCE's Capacity Bidding Program ("CBP") and Critical Peak Pricing ("CPP") at this time due to the programs' extremely low cost-effectiveness.

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[12] Tr. Vol. 1, 40:9-12 (PG&E/Gavelis).

[13] SCE Opening Brief, p. 21.

[14] Joint Assigned Commissioner and ALJ Ruling and Scoping Memo, A.11-03-001, et al., dated May 13, 2011, p. 8.

In its opening brief, SCE illustrates Table 2-2 as a modified cost-benefit analysis in an effort to reinforce its rebuttal testimony argument that all SCE DR programs are cost-effective.[15] On pages 8-10, DRA's opening brief fully explains that the cost-benefit analysis presented in Table 2-2[16] is a major understatement of the actual costs of demand response programs and should be disregarded. As such, SCE's arguments should be rejected.

Finally, SCE argues that "TURN erroneously claims that D.10-12-024 mandates that the administrative costs of each DR program should include IT costs."[17] DRA strongly disagrees with SCE's argument, and supports TURN's recommendation to include the costs of six software applications, that SCE claims in its general rate case ("GRC") are wholly or partially required to implement DR programs, in the cost-effectiveness tests of the respective programs here.[18] Furthermore, DRA supports TURN's conclusion: "The essence of a cost-effectiveness test is to compare all of the costs and benefits – it defies common sense for SCE to maintain that the costs from the GRC should not be included in the CE test."[19]

2.1.3. Response to SDG&E

In its opening brief, SDG&E states that "Because the PTR program has been previously approved by the Commission, SDG&E suggests that Commission consider the tests results without this program as presented in testimony. (SGE-7, p.KCM-16).."[20] DRA points out that SDG&E refers here to *Table 3: Results of program tests without PTR*.[21] Therefore, SDG&E acknowledges that its Demand Response portfolio is not cost-effective under any approach – with a Total Resource Cost ("TRC") ratio of 0.77 using SDG&E's alternate approach for calculating the A factor, and a TRC of only 0.75 when using E3's method.

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[15] SCE Opening Brief, p. 23.

[16] Table 2-2 in SCE's opening brief is a reproduction of Table III-3 of its rebuttal testimony.

[17] SCE Opening Brief, p. 19.

[18] TURN Opening Brief, p. 3.

[19] Id., p. 4.

[20] SDG&E Opening Brief, p. 4. "PTR" refers to Peak Time Rebate.

[21] Ex. SGE-7, p. KCM-16.

2.1.4. Response to CLECA

CLECA's opening brief states, "When evaluating the cost-effectiveness of DR programs, the Commission must also be cognizant of both underlying causes of load impact fluctuations and the impact of key assumptions on cost-effectiveness analysis and results."[22] CLECA's arguments should be disregarded.

The DR Reporting Template already allows for very generous benefit assumptions for DR programs. As DRA noted in its opening brief, the DR protocols assign as a benefit the full avoided generation capacity costs of a new combustion turbine ("CT") to demand response programs. This is a very generous benefit assumption for DR programs because it ***does not*** take into account the effect on market prices for capacity under the current and expected capacity surplus in California for the next several years.[23] Because DR protocols do not adjust capacity benefits of DR programs based on the current capacity surplus, DRA argues that, at a minimum, all proposed DR programs must be shown to be cost-effective. Beyond passing this initial hurdle, it would be prudent for the Commission to examine whether there is a real need for the capacity provided by the programs to meet the forecasted demand.[24]

2.2. DUAL PARTICIPATION RULES

2.2.1. Dual Participation In DR Programs Should Not Be Permitted.

In its opening brief, DRA recommended the Commission eliminate dual participation in DR programs for two reasons: (1) there is a changing DR landscape leading towards the integration of DR into the CAISO's wholesale market, and (2) the administrative burden to implement and enforce dual participation rules outweighs any incremental benefits.[25] PG&E and SDG&E agree that existing dual participation rules are costly to implement and enforce, so both support modifications to reduce costs.[26] SCE does not dispute that conforming dual participation

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[22] CLECA Opening Brief, p. 4.

[23] Ex. DRA-1/Ex. DRA-1c, p. 2-4.

[24] DRA Opening Brief, p. 4.

[25] DRA Opening Brief, pp. 15-16.

[26] DRA Opening Brief, pp. 17-18.

rules with the CAISO wholesale markets may result in additional costs.[27] SCE also acknowledges that other IOUs may be at a different point of implementation or have different costs for dual participation. However, SCE maintains that existing dual participation rules should not be modified in its service territory to prevent incurring additional costs.[28] DRA responds to the briefs of PG&E and SCE below.

2.2.1.1. PG&E Proposal Does Not Eliminate Need To Update Costly IT Systems

PG&E maintains that the administrative burdens of implementing rules concerning dual participation outweigh the benefits of increasing the amount of available DR.[29] However, PG&E does not support eliminating dual participation altogether. In its opening brief, PG&E states that it believes some dual participation options should be retained as they have been successfully applied to capture value from existing DR participants participating in both a price-responsive program and an emergency-triggered program.[30] PG&E claims that permitting dual participation in one price-responsive program and one emergency-triggered program maintains the benefits of dual participation while not creating unreasonable implementation costs. PG&E further explains that dual participation in programs offered by more than one DR provider should not be permitted, as only one DR provider can bid the load reduction of a single customer into the CAISO markets.[31] PG&E's claims should be rejected.

PG&E did not perform a benefit/cost analysis or provide quantifiable data for the record to support its proposal to permit dual participation in one price-responsive program and one emergency-triggered program. Since dual participation is currently not permitted in the CAISO's wholesale market,[32] utilities will have to modify existing dual participation rules to conform to the CAISO wholesale market requirements as DR resources are bid into the CAISO's wholesale market as Proxy Demand Response ("PDR") and Reliability Demand Response

[27] SCE Opening Brief, p. 26.
[28] Tr. p. 345, line 27 – p. 346, line 3 (DRA/Ouyang)
[29] Ex. PGE-1, p. 2-2.
[30] PG&E Opening Brief, p. 9.
[31] PG&E Opening Brief, p. 9.
[32] Tr., p. 343, lines 3-10. (DRA/Ouyang)

Product ("RDRP"). PG&E also did not address whether updates to costly IT systems will be necessary to conform to CAISO's wholesale market rules for dual participation. PG&E proposes to transition its DR programs to bid into the CAISO wholesale market as PDR and RDRP gradually from 2012-2014,[33] so constant updates to costly IT systems may be necessary to comply with CAISO market rules for dual participation. Any incremental cost will likely reduce the cost-effectiveness of PG&E's DR portfolio. Therefore, DRA's proposal to eliminate all dual participation is reasonable and should be adopted.

2.2.1.2. SCE's Claim That Not Permitting Dual Participation Would Require Update to Costly IT Systems Is Baseless

SCE states it will file tariff modifications for retail programs revising their dual participation conditions as well as other program design changes required for participation as PDR in the future.[34] SCE opposes eliminating dual participation. However, SCE concedes that the incremental impacts from dual participation in Residential Summer Discount Plan and Save Power Day Incentive program did not outweigh the administrative burden and potential for customer confusion about overlapping events.[35] SCE also acknowledges that other IOUs may be at a different point of implementation or have different costs for dual participation, so modifications may be necessary based on the utilities' own costs and internal administration.[36] SCE further states that DRA admitted to not understanding that there will be separate costs for disallowing the dual participation rules, and that DRA offered no justification or basis for incurring costs to disallow dual participation.[37] The Commission should disregard SCE's arguments.

DRA understands that in response to D.09-08-27, the utilities updated thier respective IT systems to prevent double counting of, and double payment for, a single load drop made by a customer enrolled in two programs with simultaneously called events. DRA disagrees with SCE's claim that disallowing dual participation would require additional updates to IT systems.

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[33] Ex. PGE-1, Appendix 7A.

[34] Ex. SCE-7, p. 34.

[35] SCE Opening Brief, p. 25

[36] SCE Opening Brief, p. 26.

[37] SCE Opening Brief, p. 26.

In DRA's view, disallowing dual participation should not require updates to existing IT systems. The utilities would simply stop using the capability to prevent double counting of, and double payment for, a single load drop made possible by the updates pursuant to D.09-08-027. In addition, SCE did not provide any evidence suggesting additional upgrades to IT systems are necessary if dual participation is eliminated. On the contrary, continuing to permit dual participation may require additional updates to costly IT systems to conform to CAISO wholesale market rules for dual participation as SCE also proposes to transition its DR programs to bid into the CAISO's wholesale market as PDR and RDRP from 2012-2014.[38]

SCE also stated in its opening brief that DRA incorrectly concluded that dual participation is not permitted in the CAISO markets.[39] SCE's arguments should be rejected. SCE is unable to reinforce this argument with any credible evidence. CLECA's opening testimony states that dual participation is permitted in some circumstances. CLECA based this information from a SCE data response.[40] In its opening brief, SCE merely references CLECA's statement.[41] Absent some affirmative showing (through a rule, a tariff, or other documentation), DRA urges the Commission to disregard SCE's unsupported assertion that dual participation is permitted in the CAISO market. DRA recommends the Commission adopt DRA's recommendation to disallow dual participation to avoid unnecessary updates to costly IT systems as utility DR programs are transitioned to bid into the CAISO wholesale markets as PDR and RDRP.

2.3. BASELINE METHODOLOGY

Several parties commented in opening briefs that changes to the baseline day-of-adjustment are necessary. DR Aggregators request the Commission to remove the cap on the day-of-adjustment.[42] DR Aggregators claim that this would improve the accuracy of baseline and provide appropriate payment to customers for verified reductions in demand. SDG&E

[38] Ex. SCE-03, pp. 122-124.
[39] SCE Opening Brief, p. 27.
[40] Ex. CLE-1, pp. 21-22.
[41] SCE Opening Brief, p. 27.
[42] DR Aggregators Opening Brief, p. 6.

proposes adoption of a 10-in-10 baseline with a 40 percent cap. [43] Both PG&E[44] and SCE[45] support SDG&E's proposal for a 40 percent cap.[46] The CAISO opposes any changes to the existing methodology, which is a 10-in-10 baseline with a 20 percent cap on day-of adjustment, until further analysis is concluded.[47] CLECA recommends that the Commission schedule workshops on SDG&E's proposal and urges rejection of proposals to eliminate the cap. CLECA argues that there are many unanswered technical questions that must be addressed before there are any changes in the baseline methodology, including the cap.[48] CLECA states there is evidence that elimination of the cap could result in overpayment, and the DR Aggregators' proposal fails to address the gaming issue.[49] SCE agrees with CLECA's recommendation to have a workshop on baseline issues.

SDG&E, who proposes increasing the cap to 40 percent, offers the explanation why the current 20 percent cap may have been exceeded in some instances. SDG&E states,

> Summer 2010 was an unusually cool weather year, where days preceding events were generally significantly cooler than actual event days, predictably resulting in a pre-adjusted 10-day average baseline under-representing the reference load of the event day. Not surprisingly, some customers' day-of adjustments would exceed the existing 20 percent cap.[50]

Similarly, SCE's witness, Ms. Wood, who supports the increase in cap to 40 percent,, stated during the hearings that although SCE has begun its baseline analysis, SCE had not completed its analysis. Ms. Wood said that although SCE had not completed its analysis, "[d]irectionally it seems like a change in the capping of 20 percent would be appropriate."[51] This is hardly the kind of rigorous analysis needed to make a big change in the primary measurement

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[43] SDG&E Opening Brief, p. 7.

[44] PG&E Opening Brief, p. 10.

[45] SCE Opening Brief, p. 29.

[46] *Id,* p. 30.

[47] CAISO Opening Brief, p. 4.

[48] CLECA Opening Brief, p. 4.

[49] *Id*.

[50] Opening Brief of San Diego Gas and Electric Company, August 22, 2011, p. 6.

[51] Opening Brief of Southern California Edison Company, August 22, 2011, pp. 28-29.

of demand response performance that the current baseline methodology represents. Additionally, as PG&E notes in its opening brief,

> There may be a small number of customers for whom even a 40 percent cap will not cover all of their load variability all of the time. However, these customers should be considered highly variable load who are not good candidates for DR programs that depend on a baseline to calculate their performance and incentives.[52]

Besides the necessity of conducting a thorough analysis before changing the baseline cap, DRA is also concerned with the additional potential gaming opportunities the 40 percent cap represents.

DRA agrees with the CAISO and CLECA that further analysis is needed before any changes to the existing methodology and that the Commission schedule workshops on the SDG&E-proposed change in the current 20 percent cap. Although PG&E, SCE and SDG&E support increasing the adjustment cap to 40 percent, no party—with the exception of the aggregators—support removing the cap itself. DRA recommends the Commission reject ***all*** proposals to change the existing methodology (10-in-10 baseline with a 20 percent cap on day-of adjustment) until further analysis is conducted.

3. EMERGENCY PROGRAMS

3.1. COMPLIANCE

3.2. REASONABLENESS

3.2.1. PG&E's Base Interruptible Program ("BIP") Program

In its opening brief, CLECA restates its proposal to increase the maximum hours of operation of PG&E's Base Interruptible Program ("BIP") from 120 hours to 180 hours per calendar year, to increase its cost-effectiveness.[53] PG&E agrees with CLECA's proposal.[54] PG&E further claims the proposed change will increase the cost-effectiveness of PG&E's BIP to

[52] Opening Brief of Pacific Gas and Electric Company, August 22, 2011, p. 11.

[53] CLECA Opening Brief, p. 5.

[54] PG&E Opening Brief, p. 14.

1.21 using E3's method for calculating the A Factor.[55] Since increasing BIP annual operating hours from 120 to 180 hours results in a TRC ratio above 1.0 for this demand response program, DRA agrees the Commission should approve the modified cost effective BIP program.

3.2.2. SCE's BIP Program

With regard to PG&E's proposal to screen and deter non-compliant BIP participants, SCE's opening brief comments, "DRA also agreed that if problems [noncompliance] can be solved by less costly means, which is true in SCE's case, that would be preferred."[56] As explained in DRA's opening brief, SCE makes valid arguments.[57] If SCE can demonstrate that (1) it does not have noncompliant BIP participants, and (2) it can solve the problem of noncompliant BIP participants through less costly means (e.g., high penalties for failure to perform), DRA agrees that PG&E's proposal referenced here may not need to be extended to SCE's BIP program.

3.2.3. SDG&E's BIP Program

SDG&E restated in its opening brief that it is has agreed to adopt PG&E's proposal to screen and deter non-compliant participants and has submitted a tariff update documenting the program changes.[58] DRA agrees with SDG&E on this tariff update, but maintains its recommendation that the Commission ***not*** approve SDG&E's BIP program unless the cost structures are changed to improve the program's cost-effectiveness to a TRC ratio above 1.0.[59] To the extent that the Commission allows SDG&E to continue the program, DRA also recommends SDG&E implement CLECA's proposal to increase the BIP annual operating hours from 120 to 180 hours to match the operating hours of SCE's BIP and increase the cost-effectiveness of BIP to a TRC ratio above 1.0.[60]

3.3. MEETING FUTURE NEEDS

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[55] PG&E Opening Brief, p. 14.
[56] SCE Opening Brief, p. 48.
[57] DRA Opening Brief, pp. 22, 23.
[58] SDG&E Opening Brief, p. 7.
[59] *See* DRA Opening Brief, pp. 20-22.
[60] CLECA Opening Brief, p. 5.

4. PRICE RESPONSIVE PROGRAMS

4.1. COMPLIANCE

4.2. REASONABLENESS

4.2.1. Capacity Bidding Program ("CBP")

4.2.1.1. PG&E's CBP Program

In its opening brief, PG&E states that "eliminating the day-ahead option by itself is unlikely to significantly reduce PG&E's CBP administrative costs and incentives."[61] DRA's initial proposal that the Commission only reject the day-ahead option ("CBP-DA") was based on PG&E's DR Reporting Template cost-effectiveness results showing CBP Day-Ahead with a TRC ratio of 0.73 and CBP Day-Of ("CBP-DO") with a TRC of 1.11. At the time, DRA believed that CBP-DO was cost-effective with a TRC ratio above 1.0.

DRA's position has since changed based on PG&E's rebuttal testimony. In rebuttal, PG&E states it had split the CBP budget based on the number of customers participating in the day ahead or day-of options.[62] Unfortunately, this split of costs, between day-ahead and day-of, is different from the split of benefits, i.e., load impacts, of day-ahead and day-of. PG&E maintains that this approach "resulted in the inaccurate indication that the day-ahead option was less cost effective than the day-of option."[63] PG&E's clarification in rebuttal testimony led DRA to the conclusion that CBP's cost-effectiveness should not be analyzed separately for CBP-DA and CBP-DO, but rather it should be analyzed for the CBP program as a whole. As fully explained in DRA's opening brief,[64] DRA recommends the Commission reject funding for PG&E's CBP program as a whole, unless and until PG&E makes any necessary changes to programs' cost structures to improve the cost-effectiveness to a TRC ratio above 1.0.

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[61] Id., p. 17.

[62] Ex. PGE-8, p.2-4, lns. 28-30.

[63] Ex. PGE-8, p.2-4, lns. 28-30.

[64] DRA Opening Brief, p. 27.

4.2.1.2. SDG&E's CBP Program

SDG&E's opening brief requests that the Commission adopt CBP as proposed.[65] DRA recommends the Commission reject SDG&E's CBP program, including both the Day-Ahead and Day-Of options, due to the very low TRC ratios of 0.69 and 0.65, respectively, for the two notification options of CBP. As fully explained in its opening brief, DRA recommends the Commission not approve SDG&E's CBP program unless and until SDG&E makes any necessary changes to programs' cost structures to improve the cost-effectiveness to a TRC ratio above 1.0.[66]

4.2.2. PG&E's Demand Bidding Program ("DBP")

In its opening brief, PG&E restates its proposal to move DBP into PeakChoice, and states "no party objected to PG&E's proposal to move DBP into PeakChoice (although DRA proposed to terminate PeakChoice based on its proposal to reject PG&E's alternate cost-effectiveness analysis)."[67] DRA recommends the Commission reject the demand response program created by merging DBP into PeakChoice (PeakChoice with DBP) unless and until PG&E makes a showing that it has made the necessary changes to improve the program's cost-effectiveness to a TRC ratio above 1.0.

As noted in its opening brief, DRA cannot provide an informed recommendation regarding the approval of DBP as a stand-alone demand response program due to the fact that PG&E did not provide a separate cost-effectiveness analysis for DBP in its revised DR Reporting Template dated May 27, 2011.[68] PG&E did provide a separate cost-effectiveness analysis for DBP Day-Ahead (DBP-DA) showing a TRC of 1.09 in its initial DR Reporting Template dated March 1, 2011. Pursuant to the May 13, 2011 Scoping Memo, PG&E submitted a revised DR Reporting Template dated May 27, 2011, but no longer provided a separate cost-effectiveness analysis for DBP-DA. As a result, it is impossible for the Commission to determine whether DBP as a stand-alone program is cost-effective. Based on the lack of this cost-effectiveness analysis for DBP only, DRA recommends the Commission require PG&E to resubmit cost-

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[65] Id., p. 9.

[66] DRA Opening Brief, pp. 24-28.

[67] PG&E Opening Brief, p. 18.

[68] DRA Opening Brief, p. 31, 32.

effectiveness results for DBP before considering the approval of DBP as a stand-alone demand response program.[69]

4.3. MEETING FUTURE NEEDS

5. INDIVIDUAL UTILITY PROGRAMS

5.1. COMPLIANCE

5.2. REASONABLENESS

5.2.1. PG&E

5.2.1.1. PeakChoice

In its opening brief, PG&E defends PeakChoice's low TRC ratio, and refers to attributes other than cost-effectiveness that the Commission should consider in determining whether a program proposal is reasonable.[70]

This argument is not new. SCE raised this issue in rebuttal testimony, where it complained DRA placed too much emphasis on cost-effectiveness. In opening briefs, DRA responded that it does not dispute that there are other factors—such as those listed in the Scoping Memo—that may provide useful information in determining whether a DR program is just and reasonable under Section 451. As DRA more fully explains in its opening brief, the DR Template (adopted in D.10-12-024 for the purposes of evaluating the cost-effectiveness of 2012-2014 DR programs) brings together for consideration into one place, most of the factors raised in the Scoping Memo.[71] Since the DR Template considers most of the benefits and costs of any consequence, DR cost-effectiveness results should be the Commission's primary and necessary test in determining whether a DR program should be approved. In DRA's view, cost-effectiveness ***should be the most important factor*** in determining whether adoption of a program is a necessary and reasonable ratepayer investment.[72]

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[69] DRA Opening Brief, p. 29-32.

[70] PG&E Opening Brief, p. 19.

[71] DRA Opening Brief, p. 5.

[72] *Id.*

The Commission should draw a line to keep ratepayers from continuing to subsidize expensive, non-cost-effective programs. Therefore, DRA reaffirms its recommendation to reject PG&E's PeakChoice program at this time due to the program's unacceptable cost-effectiveness.

5.2.1.2. Peak Day Pricing ("PDP")

In its opening brief, DRA recommends the Commission only consider PG&E's request for $6.55 million in funding for measurement and evaluation ("M&E") and personnel to support the notification for PDP, if the Commission rejects both petitions to modify D.10-02-032.[73] PG&E does not dispute DRA's argument that the cost to implement opt-in PDP should be lower than the cost to implement default PDP.[74] In its opening brief, PG&E stated that while future Commission decisions on the Petitions for Modification ("PFMs") that delay PDP implementation dates may reduce the need for some of the requested notification funding, it is unable to assess whether its request can be reduced at this time.[75]

DRA is not convinced that PG&E cannot determine if its request can be reduced at this time. PG&E should have all the information necessary to determine the total amount of funding PG&E received and spent on dynamic pricing and rate-related programs. Due to the delay in implementation of default PDP for small commercial and industrial customers, it is highly probable that PG&E has unspent funding from the $124 million granted in D.10-02-032 to implement default PDP and optional CPP and time-of-use rates from 2008 through 2010.[76] DRA urges the Commission to direct PG&E to use the unspent funding from the $124 million granted in D.10-02-032 and reassess the funding needs in its next GRC Phase 1 cycle.

5.2.2. SCE's Summer Discount Program ("SDP")

On SDP, SCE's opening brief states, "This was unopposed and uncontested. The Commission should approve SCE's proposal."[77] While it is true that DRA did not raise any issues with regard to SCE's Summer Discount Program as proposed in the instant application, DRA notes that SCE's update to SDP is currently under submission in Application 10-06-017.

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73 DRA Opening Brief, p. 62.

74 Tr. p. 321, lines 16-23.

75 PG&E Opening Brief, p. 28.

76 DRA Opening Brief, pp. 63-64.

77 SCE Opening Brief, p. 41.

By not submitting testimony as to the SDP issues in this application, DRA does not waive its objections raised in A.10-06-017. In order to best align SCE's requests in both applications, DRA recommends that any determination of SDP as requested in this application be held in abeyance until a final decision is issued in A.10-06-017.

5.2.3. SDG&E's SCTD Proposal

SDG&E's opening brief describes its describes its SDTD proposal, stating, "Although this initial proposal is not cost-effective, it will become more cost-effective as the costs at the filing of the AL will most likely be less."[78] Furthermore, SDG&E states that "this program is subject to further approval by the Commission. The final design and implementation strategy will be informed by the RACT pilot (that will be completing at the end of 2011) and approval will be requested via an Advice Letter."[79] SDG&E's request should be denied.

As stated in DRA's opening brief, DRA is concerned about the completion date of the Residential Automated Controls Technology ("RACT") pilot, which is supposed to provide information for program design.[80] Even after the completion of the pilot, DRA would like to examine the final design of SDG&E's SCTD program, including SDG&E's claim in opening brief that SCTD will become more cost-effective, before the Commission approves the program. In addition, DRA recommends the Commission not approve SCTD until the program's cost structures are changed to improve the program's cost-effectiveness to a TRC ratio above 1.0.

5.3. MEETING FUTURE NEEDS

6. ENABLING TECHNOLOGIES (INCLUDING TA, TI, AUTO DR AND PLS)

6.1. COMPLIANCE

6.2. REASONABLENESS

As PG&E notes in its opening brief, the Permanent Load Shifting ("PLS") Study states,

> "A number of emerging PLS technologies do not pass the TRC cost test at their current costs. The Joint utilities and CPUC will need to decide whether to encourage these technology types. These include most, if not all of the technologies in the battery storage

[78] SDG&E Opening Brief, p. 14.

[79] *Ibid*.

[80] DRA Opening Brief, p. 36-38.

space providing PLS, as well as 'small' thermal storage systems, even assuming an idealized operating profile." [81]

PG&E further observes that the incentive levels higher than those proposed by PG&E will encourage non-cost-effective installations, at the expense of non-participating ratepayers, and therefore are not reasonable.[82] However, as shown in the following table, neither the IOUs' PLS programs nor the vendors' PLS programs are even close to being cost-effective. Apparently, CSEA did not even provide a cost-effectiveness analysis for its PLS proposal and ICE Energy's analysis is deficient. As such, DRA recommends the Commission reject ***all*** of the PLS proposals by the vendors and also reject IOUs' PLS proposals unless and until additional changes are incorporated to make their PLS programs cost-effective.

Table 1: DRA Comparison of PLS Proposals

	PG&E	SCE	SDG&E	ICE Energy	CALMAC	CSEA
Target	New Construction and Retrofit	Incentives for Mature and RFP for Emerging technologies	TES and Deep cycle batteries	Multi-technology	Mature technologies	50% Mature and 50 % developing technologies
Size	27.5 MW	17.8 MW mature; 1 MW emerging	4.9 MW			
Total Cost	$15.1 M	$14.2 M	$3.07 M			$120 M
Incentives	$250kW-$500/kW	$545/kW for mature; S3,000/kW for emerging	$500/kW	$2,000/kW	1,200/kW - 1,500/kW	$650/kW to $3,250/kW
TRC B/C	0.7 [83]	0.77 [84]	0.45 [85]	? [86]	0.6 [87]	No C/E

81 PG&E Opening Brief, p.36.

82 *Id*.

83 *Id*, p. 32

84 SCE Opening Brief, p.56

85 Ex. SGE-12.

86 PG&E Opening Brief, pp 39-42.

87 *Id*, p. 37.

Ratio	PG&E claims ICE Energy uses faulty reporting templates	Based on PG&E's proposal at CALMAC's incentive levels	Analysis[88]

6.3. MEETING FUTURE NEEDS

7. MARKETING, OUTREACH AND EDUCATION

7.1. COMPLIANCE

7.2. REASONABLENESS

7.3. MEETING FUTURE NEEDS

8. MEASUREMENT AND VERIFICATION

8.1. COMPLIANCE

8.2. REASONABLENESS

8.3. MEETING FUTURE NEEDS

9. PILOTS

9.1. COMPLIANCE

9.2. REASONABLENESS

9.2.1. PG&E's HAN Integration Pilot Should Be Rejected

In its opening brief, CLECA strongly opposes PG&E's proposed $35 million HAN project. CLECA states the request "does not belong in this docket; it is a smart grid project, not a DR program."[89] CLECA also says the project is premature, as there is no way to demonstrate whether or not the device—utilizing Smart Energy Profile ("SEP") 2.0—will even work with PG&E's meters. Although the project is limited to 2000 residential and small commercial customers, PG&E would "*spend millions of dollars studying a device which does not exist except in prototype and which may not be compatible with existing meters, all at … ratepayer*

[88] *Id*, p. 37.

[89] CLECA Opening Brief, p. 15.

expense."[90] Finally, CLECA states PG&E's HAN pilot is too expensive, and rendered duplicative by D.11-07-056, which recently authorized a different HAN pilot. CLECA raises concerns on whether these 2,000 devices would be incremental to the pilot authorized in D.11-07-056, and whether there may be potential overlap on the two projects, if both go forward.[91]

DRA shares CLECA's concern. In its opening brief, PG&E clarifies this concern for overlap, saying:

> PG&E's DR-HAN Integration proposal is unique from that of other previous directives from the Commission as it creates the foundation for DR programs using home area network technology.
> …
> PG&E proposes to deliver HAN capabilities in two separately funded projects: (1) HAN Enablement, and (2) DR-HAN Integration. The first project will deliver the functionality to launch HAN-based programs that support energy awareness and conservation, including the initial phase rollout recently ordered by the Commission in D.11-07-056. The second project adds DR capabilities to this foundation.[92]

PG&E indicates that the funding for the first project, HAN enablement, is already funded by the Smart Meter Upgrade decision, D.09-03-026. But due to delays on the standards process, "PG&E placed the HAN Enablement project on hold until there is more certainty around the delivery of SEP 2.0 compliant devices in the marketplace."[93] Thus, PG&E separated the DR functionality into a separate project that ultimately became the DR-HAN Integration proposal.[94] PG&E clarifies that this project is separate and incremental from the "foundation" that will be created by the HAN Enablement project.

Given this clarification, it appears uncertain whether PG&E is asking for funding incremental to that authorized in D.09-03-026, since it appears that the funding there was not used because HAN enablement was put on hold and "ultimately became the DR-HAN

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90 CLECA Opening Brief, p. 16.
91 *Id.*
92 PG&E Opening Brief, p. 23.
93 PG&E Opening Brief, p.24.
94 *Id.*

Integration proposal."[95] Absent much more information, it appears that PG&E's $35 million request is another attempt to squeeze ratepayers.

Furthermore, in D.11-07-056, the Commission envisioned rolling out an implementation plan prior to the roll-out. It states:

> With the continuing delays in the development of SEP 2.0, it is reasonable to order SCE, SDG&E, and PG&E to work with Commission staff and to file a Tier 3 advice letter advice letter within four months to develop Smart Meter HAN implementation plans specific to each… Each implementation plan should include an estimated rollout implementation strategy, including a timetable, for making HAN functionality and benefits generally accessible to customers ***in a manner similar across all three companies***. The implementation plans shall include an initial phase with a rollout that enables up to 5,000 HAN-enabled devices to be directly connected with Smart Meters as envisioned in the decisions approving the deployment of AMI, even if full functionality and rollout to all customers awaits resolution of technology and standard issues.[96]

The decision continues to lay out the specific requirements of the implementation strategy.[97] Based on the Commission's language above, it is the Commission's interest to maintain consistency across all three utilities. PG&E responds in its opening brief that this decision was intended to "clarify and accelerate PG&E's HAN Enablement project funded by the Smart Meter Upgrade decision, and that it is "consistent with but does not include the DR capabilities proposed in the DR-HAN Integration proposal."[98] PG&E's arguments should be rejected.

It makes no sense that PG&E continue forward with this project in advance of the Tier 3 Advice Letter filing ordered D.11-07-056, without the benefit of working with Commission staff and collaboration with the other IOUs. The Commission specifically states,

> The goal of this roll out is to provide California customers with secure, private, and direct access to the disaggregated data available in the Smart Meters. ***To the extent practical, PG&E,***

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95 *Id.*

96 D.11-07-056, p. 112, 113.

97 *Id.,* p. 113; Ordering Paragraph ("OP") #11.

98 *Id.,* p. 25.

> ***SCE, and SDG&E should collaborate in order to ensure that the roll outs work towards providing a common interface for the devices of customers and third parties.***[99]

This final decision was recently adopted on July 29th of this year—months after PG&E submitted its proposed DR-HAN integration pilot in this application. The Commission should also reject any arguments PG&E may raise that it would be duplicative if PG&E would be required to resubmit these plans for approval at a later date. It is unlikely that PG&E's current application meets all of the requirements of the D.11-07-056 order. If PG&E's pilot in the instant application were to be adopted, it would be contrary to the intent of the Commission to develop a uniform rollout strategy with similar functions and benefits throughout the state.

9.3. MEETING FUTURE NEEDS

10. PG&E'S CURRENT AGRREGATOR MANAGED PORTFOLIO ("AMP")

10.1.1. PG&E's Request To Extend Aggregator Managed Portfolio Contracts Through 2012 Should Be Rejected.

DRA's opening brief recommends the Commission reject PG&E's request to extend the AMP contracts through 2012 due to poor performance record, lack of resource needs in 2012, and low cost-effectiveness.[100] PG&E's opening brief does not dispute the accuracy of DRA's weighted average performance calculation for the AMP contracts. However, PG&E claims that the recent performance from 2009-2010 is a better indicator of the aggregators' potential to perform in 2012, since DRA's calculation included performance results from early years where aggregators did not perform well.[101] PG&E asserts that the low performance results should be excluded.[102] DRA disagrees.

PG&E's attempt to ignore the low performing years leads to biased results and overestimates the overall performance of the AMP contracts. As indicated in DRA's opening brief, the AMP contract performance may have improved somewhat over time. However, the aggregators have not had provided a sufficient track record to show that the AMP contracts'

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[99] *Id.*

[100] DRA Opening Brief, pp. 41-49.

[101] PG&E Opening Brief, p. 50.

[102] Tr. p. 467, line23 – p. 468, line 6.

weighted average performance climbed to more than 90 percent to justify the full contract payment.[103]

PG&E also stated in its opening brief that the loading order in the Energy Action Plan II ("EAP") prioritizes cost-effective DR resources over traditional-gas fired generation, even if gas-fired generation resources are less expensive.[104] DRA disagrees. Cost-effective DR resources should only receive priority over traditional-gas fired generation, if it is comparable or is better under all evaluation criteria, including cost. If multiple cost-effective resources are available, the Commission should choose resources that are the most cost-effective, to lower consumer costs. Therefore, DRA recommends the Commission reject PG&E's request to extend the AMP contracts through 2012.

11. FORWARD LOOKING ISSUES

11.1. INTEGRATION WITH STATE CALIFORNIA ENERGY POLICIES

11.1.1. Funding For The DR Portion Of IDSM Activities Should Only Be Approved For 2012, And All Future Funding For IDSM Activities Should Be Requested In EE Applications.

DRA's testimony recommended the utilities request funding for both the DR and energy efficiency ("EE") portions of integrated demand side management ("IDSM") activities after 2012 in the EE proceeding, R.09-11-014 for a more complete review by the Commission[105]. In its opening brief, PG&E stated that DRA does not oppose the amount of PG&E's bridge funding request for IDSM for 2012, and did not cite any ratepayer savings that would result from consolidating all 2013 IDSM funding request in the EE application.[106]

Since the Commission has already approved 2012 funding for the EE portion of integrated activities in D.09-09-047 in the EE proceeding A.08-07-021,[107] there is sufficient information available to evaluate the reasonableness of the utilities' 2012 funding request for IDSM activities. However, the bridge funding for EE has not been finalized in R.09-11-014, so

[103] DRA Opening Brief, p. 46.
[104] PG&E Opening Brief, p. 52.
[105] DRA Opening Brief, p. 50.
[106] PG&E Opening Brief, p. 84.
[107] DRA-1, p. 1-9.

there is no information available to evaluate the utilities' 2013 funding request for the EE portion of IDSM activities. Thus, it is premature to conclude that no ratepayer savings would result from consolidating all IDSM funding request in the EE application for 2013. Similarly, the Commission should also disregard SCE's argument that DRA's opposition to IDSM funding is purely procedural.[108] DRA urges the Commission to direct PG&E and SCE to request all 2013 and beyond funding for IDSM activities in the EE proceeding, R.09-11-014.

11.2. INTEGRATION WITH CAISO MARKETS

11.2.1. Utility Proposals

In its opening brief, PG&E raises two issues with respect to the integration of demand response programs with CAISO markets: (1) whether transitioning of its DR programs for bidding into CAISO markets as PDR and RDRP should be pursued only if shown to be cost effective; and (2) whether the CAISO's proposal to eliminate RA counting for DR programs that are not bid into the CAISO markets as PDR and RDRP should be approved.[109]

PG&E states it is currently required to bid 10 percent of DR as PDR, one program as ancillary services, and reliability DR as RDRP,[110] and that it is currently not under any obligation to bid 100 percent of its DR into the CAISO markets.[111] PG&E claims that the cost of converting all DR programs to PDR and RDRP is significant.[112] Further, those costs were not included in the PG&E's budget requests in this proceeding. But if PG&E were to add these program costs, the result would reduce program cost-effectiveness.[113] PG&E states there are only small incremental benefits to be expected from bidding the proposed DR programs as PDR.[114] PG&E recommends a stakeholder process to evaluate the incremental benefits of having

[108] SCE Opening Brief, pp. 88-89.
[109] PG&E Opening Brief, pp. 55 and 57.
[110] *Id,* p.57.
[111] *Id,* p.55.
[112] *Id,* p.58.
[113] *Id,* p.55.
[114] *Id,* p.56.

DR bid as PDR as well as identify methods to overcome barriers that increase the costs of moving to PDR.[115]

PG&E also opposed a proposal in Administrative Law Judge ("ALJ") Gamson's proposed *Decision Further Refining The Resource Adequacy Program Regarding Demand Response Resources* in the Resource Adequacy ("RA") rulemaking, R.09-10-032, issued on August 9, 2011. The proposal holds that only those DR programs that are capable of being dispatched by local area should receive local RA credit.[116] PG&E states if the proposed decision is approved, this change to DR programs would require significant additional IT infrastructure for some DR programs. PG&E states that this proposal is similar to the CAISO's proposal requiring transitioning all DR programs for bidding into CAISO markets as PDR and RDRP and lacks analysis of the costs to IOUs in relation to the benefits of the proposed change.

Finally, PG&E also opposes the CAISO's proposal that only demand response resources bid into the CAISO markets as energy or ancillary services (PDR, PL, and RDRP) should count for RA. PG&E states that such requirement would lead to excess payment by ratepayers, as they would be required to pay for DR resources and also pay for additional resources to meet the same RA needs that the DR resources now meet.[117] PG&E points out that according to CAISO witness Mr.Goodin, it would take years for all DR programs to be bid into the CAISO market as PDR, PL, and RDRP.[118]

In contrast to PG&E, SCE states its demand response proposals fully support integration with the CAISO markets.[119] SCE proposes to make ready approximately 1,300 MW to be bid into the RDRP and PDR CAISO wholesale products by 2014. This includes seven programs: Agricultural & Pumping-Interruptible ("AP-I"), BIP, Summer Discount Plan ("SDP") (residential and C&I)), CBP, DBP, and the new Ancillary Services Tariff program. SCE states that these programs can be dispatched locally. SCE states it proposes to bid in over 70 percent of

115 *Id,* p.57.
116 *Id,* p.61.
117 *Id,* p.62
118 *Id,*
119 SCE Opening Brief, p. 72.

its demand response megawatts into the PDR or RDRP products.[120] In addition, SCE states it has worked with the CAISO in a collaborative fashion to design retail programs to meet the wholesale tariff requirements including that of ancillary services.[121]

Facing the same CAISO proposals, SDG&E appears to have chosen a totally different approach. SDG&E proposes that the Commission should direct SDG&E's DR programs to provide RA, and leave DR providing only energy or ancillary service benefits to participate directly in CAISO markets.[122] SDG&E states the primary purpose of SDG&E's DR programs and rates is to provide local capacity to meet peak demand and avoid incurring costs to otherwise maintain reliability on its electrical system. SDG&E proposes that energy or ancillary services should be provided by aggregators and obtained by customers interacting with the CAISO without the IOU serving as an unnecessary middleman.[123] SDG&E does not explain how it plans to receive RA credit or whether it would incur additional IT costs not requested in this filing, if the ALJ Gamson's proposed decision is approved and only those DR programs that are capable of being dispatched by local area would receive local RA credit.

11.2.2. DRA Response

DRA is seriously concerned that the three IOUs appear to have a different perception of what "integration of DR programs with CAISO markets" means and what they are required to achieve through integration. If these issues are not properly addressed in the current IOU application, additional IT costs may be necessary to achieve those requirements. As discussed above, PG&E has already put the Commission on notice that only 10 percent of its DR programs are capable of bidding into the CAISO's energy or ancillary services (PDR, PL, and RDRP) markets, and substantial additional IT costs beyond those included in this proceeding would be necessary to do this for the remaining 90 percent of the programs.. It is not clear if SCE and SDG&E would also incur substantial additional IT costs to integrate DR programs with CAISO's markets.

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[120] *Id.*

[121] *Id.*

[122] SDG&E Opening Brief, p. 20.

[123] *Id.*

DRA recommends the Commission establish a stakeholder process similar to that recommended by PG&E to resolve the issues surrounding integration of DR programs with CAISO markets. The stakeholder process should, at a minimum, establish (1) the scope of DR integration with the CAISO markets, (2) whether dynamic pricing programs could be and/or should be integrated with the CAISO markets, (3) the scope of DR modifications necessary to meet ALJ Gamson proposed decision's dispatchability requirements to receive local RA credit (4) any additional IT costs not requested in this proceeding but are necessary for full integration with the CAISO markets, (5) effect of additional costs on the cost-effective analysis of IOUs' proposed DR programs.

11.3. DEMAND RESPONSE MARKET COMPETITION

11.4. FUTURE AMP CONTRACTS

11.4.1. The Commission Should Only Consider New Contracts After Approving Final Rules For Direct Participation.

In its opening brief, PG&E stated the aggregators' inability to earn a capacity payment may dampen the amount of third-party DR that is bid into the CAISO markets by entities other than load serving entities ("LSEs"), so aggregator contracts are necessary in the next several years.[124]

DRA disagrees that this is adequate justification for considering new aggregator contracts. On the contrary, DRA believes this is justification for *not* considering new aggregator contracts. If the utility programs continue to provide capacity payments while the CAISO markets do not, it is obvious aggregators will only participate in the utility programs, thereby hindering the development of a direct participation market. The Commission must ensure a level playing field to avoid undermining direct participation in the CAISO wholesale market. DRA recommends the Commission wait until the final rules for demand response provider ("DRP") participation in the wholesale markets are adopted before considering approval of new contracts.

SDG&E's opening brief requests that no further DR bilateral contracts be requested or approved by the Commission at this time, because bilateral contracts do not add incremental DR, but cannibalize existing programs.[125] DRA agrees that bilateral contracts should not be approved

124 PG&E Opening Brief, p. 68.

125 SDG&E Opening brief, pp. 21-25.

if they do not add incremental DR. SCE maintains in its opening brief that the Commission should leave open the option for new aggregator contracts in the future, and it does not propose to renew its current contracts or to solicit a new set of contracts.[126] The CAISO is supportive of competitive solicitation of DR resources contingent upon these contracted resources being integrated into the wholesale market.[127] Since both PG&E and SCE expressed reluctance to bid in more than 10 percent of their DR resources into the CAISO market, as required by D.09-08-027, resources from aggregator contracts are not likely to be bid into the CAISO market.[128] Therefore, DRA recommends the Commission not consider new aggregator contracts until the final rules for direct participation are finalized.

12. FUND SHIFTING RULES

12.1.1. New Fund Shifting Rules Must Be Adopted In Response To Reduction In Number Of Budget Categories.

DRA's opening brief recommends the Commission only consider reducing the number of budget categories if new fund shifting rules are adopted.[129] In their opening briefs, both SCE and SDG&E support DRA's proposed fund shifting rules that would prevent an authorized program's budget to increase by more than 50 percent without a Tier 2 Advice Letter.[130] However, SCE also stated that DRA's recommendation that no fund shifting occur between PDR and RDRP programs is unnecessary, because there are already megawatt limits imposed on the IOUs for their RDRP enrollment.[131] DRA disagrees with SCE that this additional fund shifting rule is not necessary to prevent increases in emergency-triggered program budgets.

Both PG&E and SCE acknowledge that many customers participating in BIP, an emergency-triggered program, also participate in DBP, a price-responsive program.[132] SCE also acknowledges that dual participation in an emergency-triggered program and a price-responsive

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[126] SCE Opening Brief, p. 78.

[127] CAISO Opening Brief, p. 23.

[128] PG&E Opening Brief, pp. 57-61 and SCE Opening Brief, pp. 75-76.

[129] DRA Opening Brief, p. 57-60.

[130] SCE Opening Brief, p. 79, and SDG&E Opening Brief, pp. 23-24.

[131] SCE Opening Brief, p. 79.

[132] PG&E Opening Brief, p. 9, and SCE Opening Brief, pp. 26-27.

program would result in compliance with the Commission adopted emergency-triggered program settlement and since the MW in the emergency-triggered program would not count toward the megawatt limit.[133] This would allow utilities to increase the size of emergency-triggered programs without exceeding the megawatt limit as long as new customers participate in both an emergency-triggered program and a price-responsive program. Thus, DRA's proposed fund shifting rules are necessary to prevent the expansion of emergency-triggered programs.

DRA urges the Commission to adopt DRA's proposals to (1) require the filing of a Tier 2 advice letter for authorization to increase individual DR program budget by more than 50 percent of its original budget through fund shifting and (2) prevent fund shifting between price-responsive programs and emergency-triggered programs.

13. APPROVED BUDGETS AND AUTHORIZED EXPENSES

14. REVENUE REQUIREMENT AND COST RECOVERY

14.1. Parties' Proposals

DACC/AReM argue that demand response essentially functions as a substitute for generation and therefore demand response program costs belong in generation rates.[134]

The three IOUs and CLECA all argue that demand response and dynamic pricing program costs are properly recovered as distribution costs in distribution rates. In support of their argument, these entities make four points:

1. DR program costs are functionally customer-related costs, such as customer communication and customer equipment, and are all associated with interactions with customers. Similarly, DR costs for meters, devices, IT, and billing systems have everything to do with the delivery of service to customers, and rightfully belong in distribution.[135]
2. All customers, regardless of their load-serving entity, benefit from demand response because it helps avoid or defer not just generation costs, but also address transmission and distribution problems, which affect all customers. DR programs provide local system relief during times when the distribution system is under pressure.[136]

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[133] SCE Opening Brief, p. 27.

[134] DACC/AReM Opening Brief, pp.15 & 17; *See also* Ex. DAC-1, p.2.

[135] PG&E Opening Brief, pp.72-73; SDG&E Opening Brief , pp. 25-26; CLECA Opening Brief, p.25

[136] PG&E Opening Brief, pp.76-79; SCE Opening Brief, p.86; CLECA Opening Brief, p.26.

3. Direct access ("DA") and community choice aggregator ("CCA") customers are allowed to participate in nearly all DR programs and clearly benefit from these programs DR costs should accordingly pay for their share of costs.[137]
4. Energy service providers ("ESPs") serving DA customers receive RA credit based on their share of the area load whether or not their customers enroll in the IOUs' DR programs.[138]

CLECA further points out that functionalizing and allocating the costs of DR has been undertaken in every Phase 2 of each utility's general rate case since the energy crisis. CLECA points out that DR cost recovery is more appropriately addressed in the GRC Phase 2 because: (1) it can be considered in the context of the overall allocation of utility costs, and (2) all parties interested in DR cost allocation, along with other allocation of other costs, expect to address such matters in the GRC Phase 2 proceedings.[139]

14.2. DRA Response

DRA supports the IOUs' and CLECA's position that demand response costs should be recovered as distribution costs in distribution rates. The description and functionality of these costs are clearly related to providing various benefits to LSEs' retail customers including DA and CCA customers. The result of DACC/AReM's proposal would allow DA and CCA customers to avoid demand response program costs altogether and force other customers to bear all the costs. DACC/AReM's argument rests solely on its belief that DR is equivalent to just another generation resource and therefore any costs related to DR should only be recovered in generation rates. DACC/AReM's argument conveniently ignores the substantial benefits DR provides towards grid reliability. All Californians—including DA and CCA customers—benefit when the IOUs procure preferred resources such as energy efficiency and DR instead of the conventional generation. PG&E cites D.10-12-035, where the Commission recognizes the principle that DA and CCA customers "who benefit from procurement should pay their fair share of the procurement costs."[140] PG&E also cites several instances where, although certain costs were

[137] PG&E Opening Brief, pp.74-76; CLECA Opening Brief, p.26.
[138] PG&E Opening Brief, pp. 76; CLECA Opening Brief, p.26.
[139] CLECA Opening Brief, pp 24-25.
[140] PG&E Opening Brief, p. 79.

clearly recognized as generation-related, the Commission has ruled that DA/CCA customers are required to pay a share of these costs.[141]

DRA agrees with PG&E that characterizing DR resources as "generation resources" should not allow DA/CCA customers to escape responsibility to pay their fair share of the costs, as DA/CCA customers benefit from these programs.[142] DRA also agrees with PG&E and CLECA that the issues related to the cost recovery of Dynamic Pricing programs is out of the scope of this proceeding and that the proper venue to consider cost allocation issues is the Phase 2 of each utility's GRC.

15. CONCLUSION

WHEREFORE, based on the arguments set forth in the opening and reply briefs, the DRA respectfully requests the Commission adopt DRA's recommendations. In summary, DRA recommends the following:

1. The Commission should reject DR programs that are not cost-effective, (i.e., with a TRC ratio below 1.0).

2. Dual participation in DR programs should be eliminated to reduce administrative costs associated with implementing and enforcing dual participation rules and to align retail programs with the CAISO's wholesale market participation rules.

3. In order to maintain consistency and avoid duplicative funding requests, the Commission should not issue final decision on SCE's request for SDP funding in this application, until a final determination in A.10-06-017 is made.

4. Funding for IDSM activities should only be approved for 2012, and all funding for future IDSM activities should be made in the Energy Efficiency proceeding, Rulemaking (R.) 09-11-014.

5. The Commission should reject PG&E's $35 million proposal for a DR-HAN integration pilot.

6. PG&E's AMP contracts should be allowed to expire in 2011 without extension, and new aggregator contracts should only be considered after final rules for DRP participation in the CAISO's wholesale market are developed.

141 PG&E Opening Brief, pp. 79-80.

142 *Id*, p.80

7. There should be no fund shifting between PDR and RDRP, and any increase in a program's budget from fund shifting in excess of 50 percent of its original budget should require the filing of a Tier 2 advice letter.

8. The Commission should direct the utilities to request all future funding for dynamic pricing and rate-related programs in Phase 1 of their respective general rate cases to determine the total revenue requirement for each program and assess whether the programs should be continued. If the funding consolidation cannot be done during the utilities' current GRC cycle, the funding consolidation should begin in the utilities' next GRC cycle.

Respectfully submitted,

/s/ LISA-MARIE SALVACION

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September 9, 2011